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On the integration of sequential supplementary firing in natural gas combined cycle for CO_2-Enhanced Oil Recovery: A techno-economic analysis for Mexico

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Abstract

A techno-economic analysis of a natural gas combined cycle (NGCC) integrated with MEA-based CO_2 capture with an advanced configuration is carried out. Sequential supplementary firing in the Heat Recovery Steam Generator (HRSG) is combined with a supercritical combined cycle for the purpose of increasing CO_2 production for Enhanced Oil Recovery (EOR) at a competitive levelised cost of electricity. Supercritical steam conditions with a double reheat in the steam cycle are used to largely improve performance and take full advantage of sequential supplementary firing in the HRSG. Sequential supplementary firing increases the flue gas temperature throughout the Heat Recovery Steam Generator (HRSG) by burning additional fuel at different stages to maximise the use of oxygen available in the flue gas exiting the gas turbine. The positive impact on the post combustion capture plant size and energy requirements for solvent regeneration are attractive for markets with cheap natural gas, and where the emphasis on capital cost reduction is important. This study then investigates the effect of fuel prices and capital costs for this configuration and compares it with a typical combined cycle integrated with MEA-based CO_2 capture. A case study for Mexico is presented, at a range of gas prices where these modifications would be attractive, with a tentative target of \$40/tCO_2.

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Keywords: Sequential supplementary firing; supercritical steam cycle; carbon capture; single pressure.

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1. Introduction

Mexico intends to reduce "its GHG emissions by 50% below 2000 levels by 2050" [1]. In 2012, the Mexican Congress approved the General Climate Change Law to reduce greenhouse gas emissions and recent policy shifts have recognised the potential for Enhanced Oil Recovery (EOR) and shale gas opportunities. One of its strategies to reach this objective is the application of Carbon Capture and Storage (CCS) on fossil fuel power plants and in the oil industry, which will require large amounts of CO_2 for EOR [2] between 2020 and 2050. Annual electricity demand in Mexico is estimated to grow from 259 to 446 TWh_e between 2011 and 2026 [2]. It is expected that this rising demand for electricity would be met by an increase in the use of coal and gas, with natural gas being the dominant energy source in 2027. In the past 10 years, the fraction of natural gas in electricity generation in Mexico increased significantly from 17.1% (32.9 TWh_e) in 2000 to 50.4% (130.6 TWh_e) in 2011 [2].

1.1. Potential for EOR in Gulf of Mexico

The largest emitting region of CO_2 is the Gulf of Mexico which emits 20.1 million tons per year. It is the location of large Mexican oil fields, which make a good opportunity for EOR. The Mexican State company Petróleos Mexicanos (PEMEX) expects a need of up to 50 million tons of CO_2 in the near future [3]. The national electricity utility, Comisión Federal de Electricidad (CFE), currently operates several fossil fuel power plants around PEMEX oil fields in the Gulf of Mexico [3]. With favourable conditions for CO_2 source-to-sink matching, and given the large expected demand of CO_2 from PEMEX, CO_2 for EOR could potentially be the preferential route for geological storage of CO_2 in Mexico with associated economic benefits, and an intermediate step towards large scale decarbonisation of power generation with CCS eventually transitioning to aquifer storage.

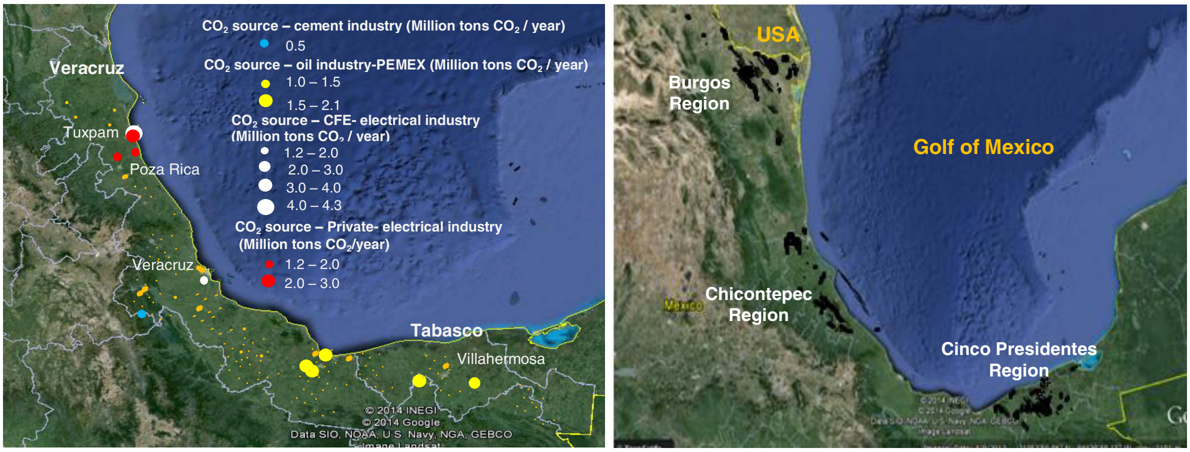

Figure 1. Localisation of industrial CO_2 sources (LHS) and the main oil reservoirs in the Gulf of Mexico region (RHS) [3].

1.2. Using affordable natural gas to produce low-carbon electricity and a revenue stream from CO_2 sales, with an indicative target of \$40/tCO_2

Anecdotal evidence suggests that a CO_2 selling price around 40 (+/- 10) \$/tCO_2 may be an acceptable proposition for CO_2-EOR projects.

This work assesses the feasibility of producing CO_2 and a competitive electricity selling price from NGCC power plants to achieve this indicative target using sequential firing in the HRSG with double reheat and supercritical steam cycle to boost CO_2 production at limited additional capital costs. A sensitivity analysis is carried out to examine the robustness of the CO_2 cost target to fuel price, capital costs etc. and examine whether the reduction in the investment cost of the CO_2 capture process can be justified.

2. Carbon capture plant on a NGCC power plant

The incorporation of post-combustion carbon capture in a natural gas power plant has mainly three challenges when compared with coal power plants. These engineering challenges may have impacts on the capital and operational costs. They are, however, mitigated in the case of supplementary firing.

1. CO_2 concentration in the exhaust gases. A typical CO_2 concentration in the exhaust gases in a coal power plant is approximately between 10-15% and in gas turbine 2-4%. Low concentration of CO_2 in the exhaust gases affects the electricity output penalty of capture because of the lower driving force for CO_2 absorption and the associated increase in absorber size and solvent energy of regeneration [5].
2. O_2 concentration. A high oxygen concentration from a natural gas turbine increases the oxidative degradation of the solvents; it means that high levels of oxygen will increase the operational costs. The degradation products may also result in additional corrosion [6].
3. High amount of exhaust gas volumes overall leading to higher capital costs [7].

A sequential firing case with a supercritical combined cycle is analysed and compared with a typical combined cycle integrated into a post-combustion capture amine plant (reference case) in order to evaluate the effect on the plant efficiency and associated implications for the capital cost of the CO_2 capture system.

The combined cycle and the amine capture plant have been simulated by using Aspen Plus with a rate-base model to simulate the absorber column. In both cases steam is extracted from the crossover pipe between the intermediate pressure and the low pressure turbines of the steam cycle.

The technical basis for the base case study is described in Table 1. The configuration of the base case comprises two GE 937 IFB gas turbines with the flue gas exiting into two HRSGs, which jointly supply steam to a subcritical triple pressure steam cycle comprising three steam turbines, as shown in Figure 2. The input data used in this study was taken from a comprehensive study by PB Power for the IEAGHG [8].

Table 1. Input data base case gas turbine.

Concept	Unit	Value
Gas turbine power output GT (x 2)	MW	590.5
Steam cycle power output	MW	343.6
Natural gas mass flow (x 2)	kg/s	33.2
Natural gas calorific value LHV	kJ/kg	46510
CO_2 mass flow (x 2) to capture plant	kg/s	88
Flue gas composition		
H_2O	% vol	7.906
CO_2	% vol	4.214
O_2	% vol	12.056
N_2	% vol	75.823

A system scheme of a combined cycle integrated with post-combustion capture using MEA is shown in Figure 2.

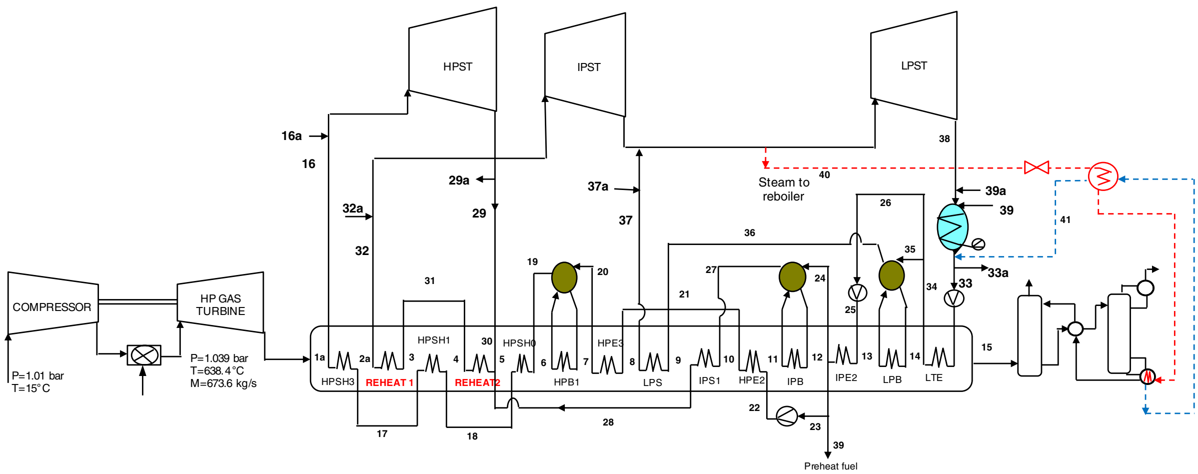

Figure 2. Schematic process flow diagram of the base case configuration 2GE 937 IFB with 2 HRSG integrated with CO_2 capture plant.

3. Sequential supplementary firing with a supercritical steam turbine combined cycle (SSFCC)

Supplementary firing makes use of the large amount of excess air used to moderate flame temperature in the gas turbine combustor. Additional fuel in supplementary burners typically located at the inlet duct of the HRSG is combusted using the excess oxygen levels in the exhaust gas to increase steam production rates compared to an unfired unit. It has traditionally been used to respond to peaks in demand at high electricity prices by increasing output - and revenues - at the expense of a reduced thermal efficiency of the cycle [9]. The maximum additional heat input in a single in-duct burner arrangement is limited by the temperature constraint for heat exchangers in the HRSG and the maximum CO_2 concentration and power output are therefore restricted.

With a driver for large amount of CO_2 for EOR in Mexico, the use of supplementary firing as a base-load strategy is, however, an attractive option to generate low-carbon electricity and a large volume of CO_2 sales by using affordable North American natural gas at limited additional capital costs. With sequential supplementary firing, additional fuel is burnt in consecutive stages throughout the HRSG. The maximum additional heat input in a single stage of sequential firing is, likewise, limited by temperature constraints on heat exchangers, but several stages are possible. The use of additional fuel is ultimately limited by the minimum excess oxygen limit for natural gas combustion, typically of the order of 1% excess oxygen. As a consequence of the large increase in steam cycle output, only a single GT train is needed to achieve the same output as a standard CCGT power plant, and, with a large fraction of the total output being generated by the combined cycle, an increase in the steam cycle efficiency by transitioning to advanced supercritical steam conditions ensures that an acceptable overall efficiency can be maintained.

The sequential supplementary firing with a double reheat supercritical steam turbine combined cycle (SSFCC) configuration proposed in this work achieves the same power output as the reference configuration with a single GE 937 IFB gas turbine, a single HRSG and a single pressure supercritical steam cycle with three turbines, as shown in Figure 3. The output of the steam cycle is 673.1 MW compared to 343.6 MW for the reference case.

The HRSG is a Once Through Steam Generator (OTSG) where supplementary gas is burned in 5 stages, as proposed in Patent 20040148941 A1 [10], to use the excess O_2 down to a concentration of 1 % v/v. The peak temperature after the first three stages of additional gas combustion reaches 820°C, then around 790ºC in the fourth stage and 700ºC in the last stage. It is an optimal arrangement of the in-duct burners and the respective heat recovery sections to ensure minimum irreversibilities and maximum steam production. CO_2 concentration in the exhaust gas is close to stoichiometric limits and twice larger than the levels in a conventional unfired NGCC. Although subcritical combined cycles are typically used for NGCC plants, supercritical cycles with double reheat are now routinely used in coal-fired steam plants and can take full advantage of sequential supplementary firing in the HRSG to largely improve performance.

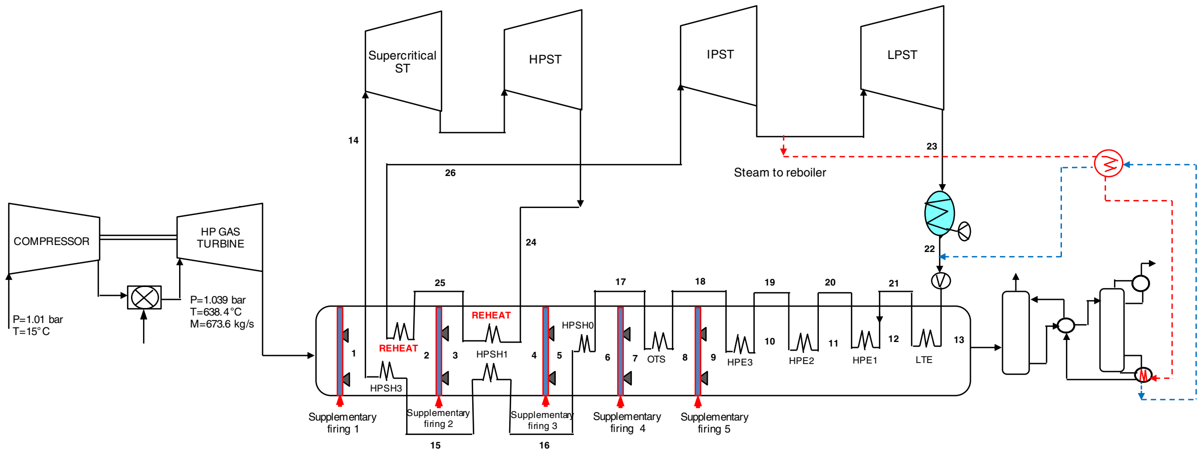

Figure 3. Schematic process flow diagram of a sequential supplementary firing with a double reheat supercritical steam turbine combined cycle.

4. Heat Recovery Steam Generator Design

The pinch diagram for the hot gas turbine exhaust and the steam cycle water/steam flow rates are shown in Figure 4 and 5 for the standard reference plant and the SSFCC configuration, respectively. With sequential supplementary firing, supercritical steam conditions (630ºC, 601.5, 290 bar) increase the average temperature of heat addition to the steam cycle due to the absence of phase change from the HP evaporator to the HP superheater.

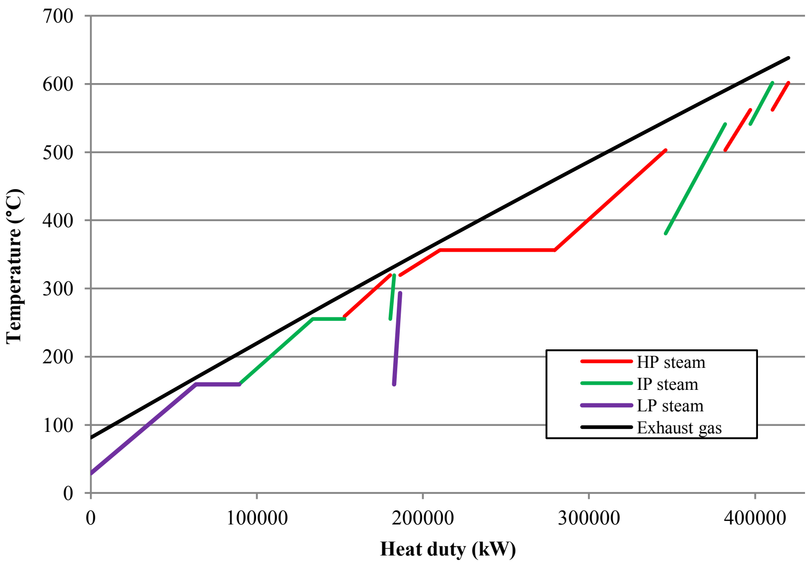

Figure 4. Pinch diagram of the Heat Recovery Steam Generator of Natural Gas Combined Cycle plant with subcritical steam conditions (601.7°C, 601.5°C, 172.5 bar).

Larger irreversibilities occur in the HRSG since the gas temperature increases after each stage of duct firing above the gas turbine exhaust temperature. The marginal thermal efficiency of the additional natural gas usage in the HRSG would be of the order of 49.5% LHV, if steam extraction for solvent regeneration were not accounted for.

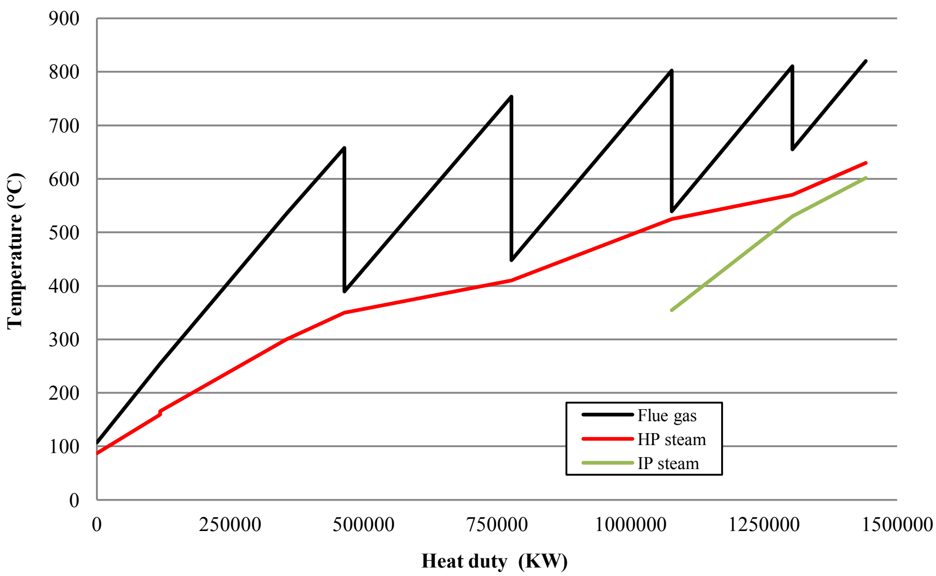

Figure 5. Pinch diagram of the Heat Recovery Steam Generator of the sequential supplementary firing combined cycle, with supercritical steam conditions (630ºC, 601.5 ºC, 290 bar).

5. Effect of increased CO_2 concentration on solvent energy of regeneration and absorber column design

The combustion of additional natural gas in the HRSG increases the CO_2 concentration in the flue gas from 4.27 % v/v to 9.36 % v/v, whilst reducing the excess oxygen to 1.1 % v/v. The higher rich loading achieved with higher CO_2 concentration leads to an increase in solvent capacity and the specific reboiler duty decreases approximately from 3.55 to 3.45 GJ/tonne CO_2 for a configuration with 21m of packing of the absorber columns, as indicated in Figure 6.

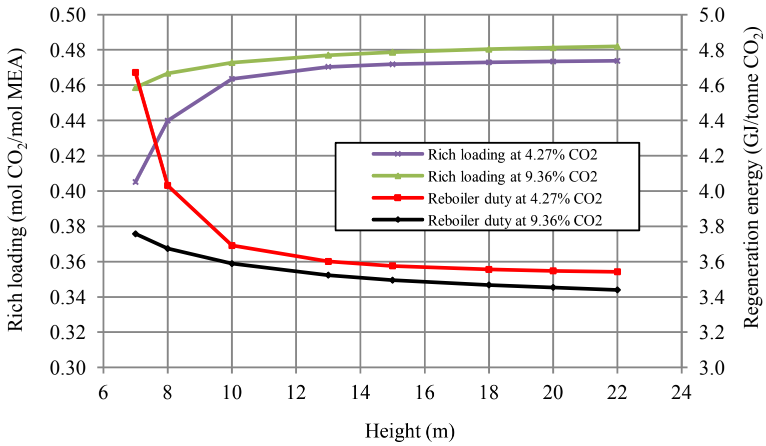

Figure 6. Effect of CO_2 concentration in the flue gas on solvent energy of regeneration for a range of absorber column heights. The capture rate is 90%.

The reduction by approximately 50% of the overall gas flow rates has a positive impact on the capital costs of the absorber columns. With 21m of packing in each absorber column, the number of columns required to treat the total volume of flue gas is reduced from four to two columns.

6. Summary of results

Key parameters are summarised in Table 2. Although the thermal efficiency of the SSFCC configuration is of the order of 47.9% LHV, compared to 53.4% for a standard NGCC plant with post-combustion capture, there are significant capital cost implications for the gas turbine, the heat recovery steam generator, the steam cycle, the absorber trains and the stripper/compression part of the capture plant:

- The SSFCC configuration makes use of a single gas turbine/HRSG train compared to two gas turbine/HRSG trains for a standard configuration.
- The number of absorber trains is reduced from four to two, as previously discussed.
- The capacity of the stripper and the compression train is increased by around 15%.
- A large part of The HRSG needs to be designed to face gas temperature in excess of 700ºC, whilst only single pressure levels are required.
- The HP part of the combined cycle, including the HP steam turbine, valves, pipework, the HP superheater and the HP "evaporator -like" superheater, requires being of supercritical design.

Table 2. Summary of key parameters of a SSFCC with single pressure supercritical steam cycle (steam condition for the reboiler T=138 ºC, 3 bar) with carbon capture

Concept	Unit	Base case	SSFCC
Gas turbine power output GT	MW	590.5	295.2
Steam cycle power output	MW	237.0	572.0
Net power output	MW	827.5	867.3
Mass flow rate of natural gas to gas turbine	kg/s	33.20	16.62
Mass flow rate of natural gas for supplementary firing	kg/s	0	22.31
Fuel calorific value (LHV)	kJ/kg	46510	46510
Net electrical efficiency (LHV)	%	53.4	47.9
Marginal efficiency of natural gas fired in HRSG (LHV)	%	-----	40.2
Marginal efficiency of natural gas fired in HRSG (LHV) without post-combustion capture (for comparative purpose purposes only)	%	-----	49.5
Flue gas composition			
H_2O	% vol	7.906	17.568
CO_2	% vol	4.214	9.360
O_2	% vol	12.056	1.132
N_2	% vol	75.823	71.940
Flue gas mass flow rate	kg/s	1347.1	695.9
CO_2 mass flow to pipeline	kg/s	79.24	92.80
Capture level	%	90	90
Carbon intensity of electricity generation	$kgCO_2/MWh$	38	42
Solvent energy of regeneration	$GJ/tonneCO_2$	3.54	3.44
Steam mass flow to solvent reboiler	kg/s	143.9	163.1
Number of absorber trains		4	2
Absorber height	m	21	21
Absorber diameter	m	15.7	15.7
Volume of packing used for CO_2 capture (not including water wash sections)	m^3	16260	8130

7. Techno-economic analysis for EOR scenarios

In the context of power generation with natural gas prices around 3-5$/MMBTU and CO_2 sales at 40(+/-10) $/t$CO_2$ for EOR in Mexico oil fields, a more detailed study is necessary to understand the full implications on capital costs. It can, however, be expected that the reduction of the number of gas turbine/HRSG trains and absorber trains will lead to significant savings that may compensate, to a certain extent, the increasing complexity of the high pressure part of the HRSG and the steam cycle.

The methodology used for the techno-economic analysis in this study uses levelised cost of electricity calculations as the initial starting point for comparison and takes into consideration the electricity selling price in the market where the plants operate. The analysis goes beyond a direct comparison of levelised cost of electricity values by assuming that three possible configurations of plants – an unabated NGCC plant, a standard NGCC plant with post-combustion capture and a SSFCC configuration with capture – receive a revenue from electricity generation at the same electricity selling price, which may be lower than their levelised cost of electricity (LCOE) [12]. The LCOE of the unabated NGCC plant is here used as the counterfactual electricity market price, with the underlying assumption that it is worth building a new NGCC plant without capture in the market where all possible three configurations of plants operate. Carbon prices are not included in this analysis.

The variations in efficiency result in variations in short run marginal costs of electricity generation, which may lead to change in load factors. These considerations are not taken into account in this analysis, since the revenue for CO_2 sales is assumed to be sufficient to justify dispatching the plant.

The revenues over the economic lifetime consist, for each possible configuration, of the sales of electricity at market price, assumed to be identical to the LCOE of the NGCC plant, and sales of CO_2 volumes for EOR. Capital cost estimates are taken for Nth Of A Kind plant, compiled for the UK [13].

Figure 7 illustrates the variations in capital costs of the SSFCC plant, for which revenues are equal to those of a counterfactual plant, which is the most profitable of either a NGCC plant w/o capture or a NGCC plant with capture and CO_2 sales for EOR, over the range of fuel prices and CO_2 prices considered. It shows changes in capital costs of the order of +/- 500$/kW could be justified for CO_2 prices and fuel prices ranging from, respectively, 30-50 $/tonne CO_2 and 3-5 $/MMBTU.

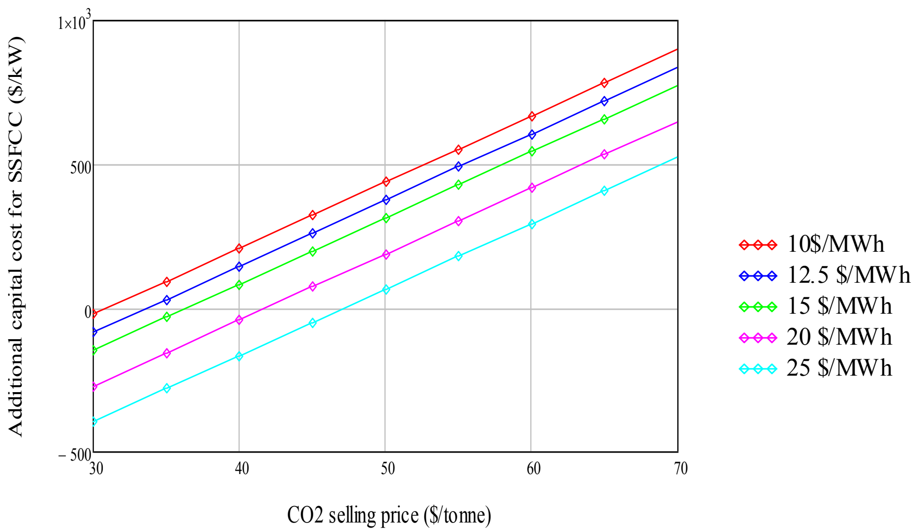

Figure 7. Breakeven variations in capital cost for a Natural Gas Sequential Supplementary Firing Combined Cycle plant for a range of representative CO_2 and fuel prices. Revenues are assumed to be the same as a counterfactual plant, which is the most profitable of either a NGCC plant w/o capture or a NGCC plant with capture and EOR. Variations in capital costs are reported compared to the capital costs of the counterfactual plant.

8. Conclusions

The integration of sequential supplementary firing in natural gas combined cycle power plants is examined in the context of deploying CCS with Enhanced Oil Recovery in Mexico. A new design of the HRSG is proposed to use additional fuel to increase available CO_2 flows for EOR by reducing excess oxygen levels as low as practically possible (of the order of 1% v/v). The thermal efficiency is reduced by 5.5% compared to a NGCC plant with capture. The increase in output of the steam cycle leads to the use of a single gas turbine/HRSG train, whilst the output is increased by approximately 5% compared to a standard CCGT power plant with two gas turbine trains.

A preliminary analysis shows that this could be justified in the context of current expectations of CO_2 prices for EOR and natural gas prices. Future work to understand the full capital cost implications of the upgrade of the HRSG and combined cycle would be necessary to develop this concept further.

Appendix A.

Table A.1. Summary of key assumptions for the evaluation of plant revenues and CAPEX

Capture level for post-combustion capture plant	%	90
Annual fixed charges for new plant, before capture basis	%	2.0
Annual fixed costs for new capture plant related to CAPEX	%	2.0
New plant compression and auxiliary power per tonne CO_2 captured	kWh/tCO_2	170
Interest rate	%	10
Plant life	years	20
Load factor for new plant, assumed to be all at full output	%	80
Capital charge rate for life	%/yr	11.7
Running hours per year for retrofit load factor	hrs/yr	7008
Variable costs for new plant, before capture basis	\$/MWh	2
Capital costs for new power plant excluding capture-related costs [13]	\$/kW	1875.2
Capital costs for new power plant including capture-related costs [13]	\$/kW	3917.7
Capture plant non-energy OPEX, based on CO_2 captured	\$/tCO_2	3
CO_2 emission price	\$/tCO_2	0
CO_2 transport and storage costs	\$/tCO_2	10

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